RESULTS OF OPERATIONS

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2010	2009	$ Change	% Change	2010	2009	$ Change	% Change
Transmission	306	271	35	13	626	573	53	9
Distribution	842	803	39	5	1,825	1,789	36	2
Other	17	16	1	6	33	31	2	6
	1,165	1,090	75	7	2,484	2,393	91	4
Average Ontario 60-minute peak demand *(MW)*[1]	20,610	19,615	995	5	20,772	20,901	(129)	(1)
Distribution - units distributed to customers *(TWh)*[1]	6.4	6.4	-	-	14.4	14.8	(0.4)	(3)

[1] System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $35 million, or 13%, in the second quarter, and by $53 million, or 9%, in the first six months, compared to the same periods last year. The average monthly peak demand was higher for the second quarter, resulting in an increase in transmission revenue of $9 million. However the average monthly peak demand was lower on a year-to-date basis, resulting in a $7 million decrease in revenue for the first six months. Among other factors, weather was generally milder over the winter months and unseasonably hot in the latter part of the second quarter.

The Ontario Energy Board (OEB) rendered its decision on our 2009 and 2010 transmission rate application on May 28, 2009 following an extensive written and oral review. The resulting tariff increases approved effective July 1, 2009 and January 1, 2010 support our investments in respect of the Ontario Power Authority's (OPA) supply mix policy, including the phase-out of coal-fired generation and addressing aging infrastructure. These increases resulted in higher second quarter revenues of $30 million and higher year-to-date revenues of $60 million. We also experienced higher revenues of $4 million in the quarter and $9 million on a year-to-date basis associated with the disposition of OEB-approved deferral accounts.

Transmission tariff revenue increases were partially offset by lower ancillary revenues of approximately $8 million in the second quarter and $9 million on a year-to-date basis due to the impact of the May 28, 2009 OEB decision. Consistent with this decision, ancillary revenues received in excess of forecasted levels are recorded in a regulatory account and are not recognized as revenue.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $39 million, or 5%, in the second quarter, and by $36 million, or 2%, in the first six months compared to the same periods last year. This change includes the recovery of higher purchased power costs of $24 million in the second quarter and $13 million in the first six months, as described below under "Purchased Power."

Increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On May 13, 2009, the OEB approved new tariff rates under the third generation Incentive Rate Mechanism effective May 1, 2009. On April 9, 2010, the OEB approved new tariff rates following our cost of service application effective May 1, 2010. Both decisions followed extensive written and oral reviews of our evidence submitted for the maintenance and investment requirements of the distribution system, including those to support renewable distributed generation. The new OEB-approved tariff rates resulted in higher distribution revenues of $17 million during the second quarter and $29 million in the first six months. These tariff rate increases support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. The April 9, 2010 decision also resulted in increased revenue related to the recovery of smart meter investments and smart grid investments of $6 million in the quarter and $12 million in the first six months.

These distribution revenue increases were partially offset by lower energy consumption of $14 million in the first six months, resulting primarily from the milder weather in the first quarter of this year. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective April 30, 2010, resulting in a revenue reduction of $4 million for both the quarter and the six month period.

We also experienced lower ancillary revenues of approximately $4 million in the quarter and nominal changes on a year-to-date basis.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5

RPP Time-of-Use	Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
May 1, 2010	9.9	8.0	5.3

Purchased power costs increased in 2010 by $24 million, or 5%, to $542 million in the second quarter and by $13 million, or 1% to $1,197 million in the first six months compared to the same periods last year. The increases in our purchased power costs were primarily due to the impact of changes in the OEB's RPP rate for residential and other eligible customers of $34 million in the quarter and $31 million in the year-to-date period, higher purchased power costs for customers who are not eligible for the RPP of $18 million in the quarter and $40 million in the first six months, and increased transmission charges due to the OEB's transmission rate decisions effective July 1, 2009 and January 1, 2010 of $8 million for the quarter and $17 million for the year-to-date period. The effect of these increases was partially offset by lower demand for electricity of $26 million in the quarter and $61 million in the year-to-date period and the impact of lower charges levied by the IESO of $10 million in the second quarter and $14 million in the first six months.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2010	2009	$ Change	% Change	2010	2009	$ Change	% Change
Transmission	103	120	(17)	(14)	210	223	(13)	(6)
Distribution	148	147	1	1	285	274	11	4
Other	15	14	1	7	29	27	2	7
	266	281	(15)	(5)	524	524	-	-

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $17 million, or 14%, in the quarter and by $13 million, or 6%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were lower by $1 million in the quarter, but were higher by $8 million on a year-to-date basis, compared to the same periods last year. The year-to-date impact was mainly associated with our planned station maintenance programs to support aging infrastructure, particularly on transformers, for corrective station maintenance and expanded forestry programs. In addition, we experienced reductions of $16 million and $21 million related to our expenditures incurred to support the transmission system in the second quarter and first six months, respectively. These reductions primarily reflect the reallocation of resources to the capital work program, partially offset by higher information technology support expenditures and infrastructure enhancements.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $1 million, or 1%, in the quarter and by $11 million, or 4%, on a year-to-date basis, compared to the same periods last year. Our work program expenditures were relatively unchanged in the quarter being higher by $1 million, and were higher by $11 million on a year-to-date basis, compared to the same periods last year. In both the quarter and the year-to-date periods, we experienced increased expenditures associated with the advancement of our forestry programs given favourable weather conditions and we had increased requirements within our station maintenance and engineering support programs. These expenditures were offset in the quarter and partially offset in the year-to-date period by lower storm restoration requirements, and lower planned line maintenance work reflecting lower field meter readings as installed smart meters begin to reach the required level of reliable communication. Our expenditures in support of our distribution system were consistent with the prior year both in the quarter and on a year-to-date basis.

Depreciation and Amortization

Depreciation and amortization expense increased by $15 million, or 12%, to $144 million in the second quarter and by $30 million, or 12%, to $283 million in the first six months compared to the same periods last year. These increases were mainly attributable to new assets coming into service, consistent with our ongoing capital work program. In addition, higher expenditures necessary to comply with Environment Canada's regulations on the removal of polychlorinated biphenyls increased the amortization of our related environmental regulatory asset. These increases were partially offset by the completion of amortization of a distribution regulatory account during the second quarter.

Financing Charges

Financing charges increased by $14 million, or 19%, to $88 million in the second quarter and by $27 million, or 18%, to $173 million for the year-to-date period compared to last year. These increases were primarily due to a net increase in interest expense reflecting a higher average level of debt to support capital requirements, partially offset by a lower average effective interest rate. In addition, although we had higher levels of construction in progress, we capitalized less interest due to lower OEB-approved interest capitalization rates.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $14 million, or 233%, to $20 million in the second quarter and by $6 million, or 22%, to $33 million on a year-to-date basis, compared to the same periods last year. The

quarterly increase was primarily due to higher pre-tax income this year, partially offset by a reduction in the statutory rate from 33.0% to 31.0%. Also contributing to this increase were lower temporary differences related to depreciation and the capital cost allowance being claimed on our fixed assets. In the year-to-date period, the increase in the provision was due to higher pre-tax income, temporary differences related to capital cost allowance and depreciation, and higher future income taxes, partially offset by the reduction in the statutory rate and by temporary differences associated with the recovery of certain regulatory accounts.

Net Income

Net income of $105 million in the second quarter and $274 million year-to-date was higher by $23 million, or 28%, and by $15 million, or 6%, respectively, compared to 2009 results. Net income was higher primarily due to increased revenues in both periods as a result of the OEB-approved transmission tariff rate increases that were effective July 1, 2009 and January 1, 2010 which support investments in respect of the OPA's supply mix policies, which include the phase-out of coal-fired generation and investments to address aging infrastructure. Also contributing to higher net income in both periods were increased revenues as a result of the OEB decisions in respect of our distribution rates effective May 1, 2009 and May 1, 2010 that support necessary maintenance and investment requirements of our distribution system. The impact of increased tariffs on net income was partially offset by higher financing charges and higher depreciation in both periods.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2008 through June 30, 2010. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2010**			**2009**			**2008**	
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31[2]**	**Sep. 30**
Total revenue[1]	1,165	1,319	1,207	1,144	1,090	1,303	1,194	1,126
Net income[1]	105	169	111	100	82	177	131	112
Net income to common shareholder[1]	100	165	106	96	77	173	126	108

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, other investing activities, and dividends.

Summary of Sources and Uses of Cash	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2010**	**2009**	**2010**	**2009**
Operating activities	257	192	544	373
Financing activities				
Long-term debt issued	-	-	1,000	600
Long-term debt retired	(400)	-	(400)	(400)
Short-term notes payable	-	75	(55)	225
Dividends paid	(5)	(27)	(19)	(135)
Investing activities				
Capital expenditures	(383)	(383)	(705)	(719)
Long-term investment	-	-	(250)	-
Other financing and investing activities	12	3	19	20
Net change in cash and cash equivalents	(519)	(140)	134	(36)

Operating Activities

Net cash from operating activities increased by $65 million, to $257 million in the second quarter, and increased by $171 million to $544 million in the first six months, compared to 2009. These increases primarily reflect improved accounts receivable collection cycles, partially offset in the quarter by lower revenue levels. Operating activities were further positively impacted in both periods by changes to accounts payable balances due to variances in purchased power costs related to the demand for electricity and changes to certain regulatory accounts, particularly retail settlement variance accounts.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes.

At June 30, 2010, we had no short-term notes outstanding. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. During the quarter, we increased the amount of our $500 million revolving credit facility, entered into in the first quarter, to $1,250 million and we extended the term of the facility to June 2013. We also cancelled the $750 million revolving credit facility which would have matured in August 2010.

At June 30, 2010, we had $7,475 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August, 2011 is $3,000 million, of which $1,750 million was remaining and available as at June 30, 2010.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide

limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as of June 30, 2010.

In the year-to-date period of 2010, we issued $1,000 million in long-term debt under our Medium-term Note Program in the first three months and we made second quarter repayments of $400 million in maturing long-term debt. In the comparative period last year, we issued $600 million in long-term debt under our Medium-Term Note Program and repaid $400 million in maturing long-term debt during the first three months, and did not issue any long-term debt nor were there any debt maturities during the second quarter. During the first six months of this year, we reduced our short-term notes by $55 million, all in the first quarter, and in the comparative period of 2009 we increased our short-term notes by $150 million and $75 million in the first and second quarters respectively.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Consistent with the comparative periods in the prior year, we paid preferred dividends of about $5 million to the Province of Ontario (Province) in the second quarter and $9 million on a year-to-date basis. We also paid common dividends of $10 million, all in the first three months of this year, compared to $104 million and $22 million in the first and second quarters of 2009, respectively.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**	**2010**	**2009**	**$ Change**	**% Change**
Transmission	209	218	(9)	(4)	404	405	(1)	-
Distribution	174	163	11	7	300	311	(11)	(4)
Other	-	2	(2)	(100)	1	3	(2)	(67)
	383	383	-	-	705	719	(14)	(2)

Transmission

Transmission capital expenditures decreased by $9 million, or 4%, to $209 million in the second quarter, and decreased slightly by $1 million to $404 million in the first six months, compared to the same periods in 2009.

Expenditures to expand and reinforce our transmission system were $104 million in the quarter and $211 million for the first six months of the year, representing a decrease of $12 million and an increase of $8 million over the respective comparable periods. We continued to invest in a number of inter-area network upgrade projects to support the OPA's supply mix objectives for generation. We also continued to make investments in our local area supply projects to address growing loads. For the quarter, these expenditures were more than offset by a reduction in expenditures in our load customer connection projects, a reduction in expenditures associated with local area supply projects that were substantially completed earlier this year, and the near completion of certain inter-area network projects.

Inter-area network upgrades with significant expenditures included the Bruce to Milton Transmission Reinforcement Project, to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, and the Northeast Transmission Reinforcement Project, which will increase the North-South interface transfer capability to access available northern generation. In addition, we are installing static var compensators at Nanticoke and Detweiler Transformer Stations, which in the short-term will support increased generation from the Bruce Nuclear facility and in the longer-term, will enhance the transfer capability between South Western Ontario and the Greater Toronto Area (GTA). These investments

were partially offset by lower expenditures associated with the installation of capacitor banks in South Western Ontario. This equipment will provide interim protection to the Bruce Nuclear facility and will expand transmission capacity in South Western Ontario. In addition, we incurred lower expenditures associated with the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro-Québec interconnection. This work is expected to be completed by the end of the year.

Local area supply projects with expenditures in the second quarter of 2010 include our Woodstock Area Transmission Reinforcement Project, which will increase capacity to ensure supply reliability in the Woodstock area, and our Switchyard Reconstruction Project at our Burlington Transformer Station, which will increase the load supply capacity to ensure reliability of supply to customers in the area. The GTA West Transmission Reinforcement Project, which has increased capacity to ensure supply reliability in the area, as well as the Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which has increased transmission capacity in the Western Brampton area to allow for future load growth, were both substantially completed in the first quarter of this year, contributing to the reduction in expenditures in the second quarter compared to the prior year. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $89 million in the quarter and $161 million on a year-to-date basis, representing increases of $17 million and $25 million respectively compared to the same periods last year. These increases are primarily related to higher targeted replacements of aging components, specifically within our breaker installation and protection and control equipment programs, and to higher expenditures within our Spare Transformer Purchase Program. In the year-to-date period, we also experienced higher expenditures related to an expanded Wood Pole Replacement Program.

Our other transmission capital expenditures were $16 million in the quarter and $32 million for the first six months, representing respective decreases of $14 million and $34 over the comparative periods. These reductions from the prior year were due to expenditures in 2009 on our investment in an entity-wide information system replacement and improvement project which replaced end-of-life systems and improved productivity, the second phase of which was completed during the third quarter of last year. In addition, expenditures incurred to enhance information security at our Ontario Grid Control Centre were lower compared to the same period in the prior year as we completed a number of enhancements associated with North American Electric Reliability Corporation requirements.

Distribution

Distribution capital expenditures increased by $11 million, or 7%, to $174 million in the second quarter and decreased by $11 million, or 4%, to $300 million for the first six months, compared to the same periods in 2009.

Capital expenditures to expand and reinforce our distribution network were $85 million in the quarter and $149 million for the first six months of the year, representing reductions of $2 million and $23 million over the comparable periods, respectively. The reduction in the year-to-date period was primarily due to the substantial completion of smart meter installations across the province at the end of last year. In the quarter, the lower expenditures related to installations were offset by expenditures on the smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. Smart meter installations continued during the quarter as our total cumulative number of installations exceeded 1,282,000 as at June 30, 2010, thus nearing the program's total target. With over 561,000 meters enabled to support time of use billing as at June 30, 2010, we continue our efforts to migrate our customers to time-of-use pricing; over 126,000 of our customers are now consuming power based on time-of-use-pricing. Our program is one of the largest utility smart meter deployments in North America.

Expenditures to sustain our distribution system of $80 million in the quarter and $137 million year-to-date, increased by $18 million and $29 million, respectively, compared to the same periods last year. These increases were primarily a result of higher expenditures on transport and work equipment and the planned replacement of end-of-life wood poles. In addition, we experienced higher expenditures related to line relocation work in support of municipal road widening projects. These increases were partially offset by lower storm-recovery expenditures.

Our other distribution capital expenditures were $9 million in the quarter and $14 million for the first six months, representing respective reductions of $5 million and $17 million from the comparative periods. These reductions reflect our higher prior period investments in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures for 2010 were originally budgeted at $2.0 billion. The 2010 capital budgets for our Transmission and Distribution Businesses were approximately $1,150 million and $850 million, respectively. Capital expenditures were expected to increase to approximately $2.1 billion in 2011 and approximately $2.2 billion in 2012. These expenditures reflected the sustainment requirements of our aging infrastructure budgeted at approximately $530 million in 2010, $620 million in 2011 and $670 million in 2012. Development projects, including inter-area network upgrades that reflect the OPA's supply mix policies to phase out coal generation and local area supply requirements, were budgeted at approximately $890 million in 2010, $780 million in 2011 and $550 million in 2012. These development investments also reflected the continued mass deployment of smart meters within our Distribution Businesses and the building of the required smart meter infrastructure in support of conservation objectives. We will leverage the smart meter investment to build a smart grid which will enhance our operations and support distributed generation. Other capital expenditures related to operations amounted to approximately $410 million in 2010, $290 million in 2011 and $230 million in 2012. Our capital expenditures to support the requirements under the Green Energy Act (GEA) were budgeted at approximately $190 million in 2010, $450 million in 2011 and $740 million in 2012. We are proceeding with our investments in support of the GEA to facilitate renewable generation consistent with the Feed-in-Tariff (FIT) program. Capital expenditures of our other business segment were budgeted at about $15 million in 2010, primarily reflecting the continued build out of the fibre optic network.

As a result of factors such as ongoing discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements, as well as the OEB's distribution rate decision issued April 9, 2010, capital expenditures for 2010 are expected to be lower by approximately $400 million. In addition, on May 19, 2010, we filed a transmission rate application for 2011 and 2012 that included lower capital expenditures than budgeted of $100 million and $250 million, respectively. In respect of our Distribution Business, the OEB approved lower capital expenditures of $120 million from that originally requested in its recent decision on our distribution rate application for 2011. Many projects require external approvals or may be subject to other external influences that are outside of our control. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

June 30, 2010 (Canadian dollars in millions)	**Total**	**2010**[1]	**2011/2012**	**2013/2014**	**After 2014**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	7,475	200	1,100	1,350	4,825
Long-term debt – interest payments	6,311	199	748	628	4,736
Inergi LP (Inergi) outsourcing agreement[2]	643	73	283	265	22
Operating lease commitments	55	5	12	12	26
Environmental obligations[3]	381	16	68	79	218
Total Contractual Obligations	14,865	493	2,211	2,334	9,827
Other Commercial Commitments *(by year of expiry)*					
Bank line[4]	1,250	-	-	1,250	-
Letters of credit[5]	108	107	1	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	373	81	280	12	-
Total Other Commercial Commitments	2,057	514	281	1,262	-

[1] The amounts disclosed represent the balances due over the period July 1, 2010 to December 31, 2010.

[2] On May 1, 2010, the Company extended the Master Services Agreement (MSA) with Inergi for a further three-year period. The term of the agreement, which would have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[5] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The expenditure pattern reflects our planned work program for the period.

[5] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks which matures in June 2013.

[5] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[6] Contributions to the pension fund are made one month in arrears. Contributions for 2010, 2011 and 2012 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our pension contributions to be approximately $140 million annually starting in 2010, and variable in 2011 and 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchase payments made, to the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province and our payments in lieu of corporate income taxes, which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, we purchased $250 million Province of Ontario Floating Rate Notes, maturing on November 19, 2014 as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first six months of 2010, the deferred pension asset reported on our balance sheet decreased by $32 million to $392 million. We contributed $59 million into our pension plan and incurred $91 million in net periodic pension benefit cost. Contributions for 2010, 2011 and 2012 will be based on an actuarial valuation effective December 31, 2009 to be filed later this year and will depend on future investment returns, changes in benefits and actuarial assumptions. Based on current factors, we currently estimate our pension contributions to be approximately $140 million annually starting in 2010, and variable in 2011 and 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012.

As a result of recent financial market volatility, our pension plan experienced a negative return in the second quarter of about 4.6%, resulting in a negative return of approximately 2.6% on a year-to-date basis. The return was affected primarily by negative performance of equity investments following uncertainty in the European marketplace, as well as the resulting uncertainty surrounding the robustness of the economic recovery in North America. This negative impact on the Fund's return was partially offset by the strong performance of its fixed income holdings.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. In anticipation of this decision, we commenced our IFRS conversion project in 2007.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high level review and identification of the major differences between current GAAP and IFRS in all subject areas resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are currently tracking our comparative results under IFRS, assuming that the recognition of regulatory assets and liabilities will be permitted. We are concurrently developing plans to support accounting and business processes should rate-regulated accounting be discontinued. Our teams continue to monitor progress relative to key milestones, monitor developments of both the International Accounting Standards Board (IASB or the Board) and the AcSB, update recommendations and develop financial reports. We continue to have recurring dialogue with our external auditors about possible outcomes of our project.

We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards continue to evolve.

Accounting Policies

During 2009, both the Public Sector Accounting Board (PSAB) and the Canadian Securities Administrators' (CSA) staff confirmed that companies such as Hydro One will be required to adopt IFRS in 2011. On December 14, 2009, the PSAB issued an exposure draft proposing to remove the requirement for government organizations adhering to IFRS to also apply additional public sector financial reporting standards, currently Public Sector Accounting Handbook Section 3270. The effective date for the proposed changes is January 1, 2011.

The areas with the highest potential to significantly impact our company upon conversion to IFRS, identified during the diagnostic phase, are regulatory assets and liabilities, fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1). The IASB's project on rate-regulated activities (RRA) will have an impact on the accounting choices available in all of these areas.

In December 2008, the IASB added a project on RRA to its agenda. In July 2009, the IASB issued an exposure draft detailing its proposals for standards for the accounting of RRA. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. The exposure draft makes an exception to the requirements of other IFRS standards by allowing capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the inclusion of these costs in rate base. The IASB requested comments from interested observers on the exposure draft. We responded to the IASB's request for comment on November 24, 2009. The IASB received approximately 150 responses to its request for comment, which were very diverse in their opinions. As a result, the IASB staff postponed presenting their analysis of the responses to the IASB, originally scheduled for January, to the Board's February meeting. The presentation to the IASB in February included options for the next steps of the project.

The Board decided tentatively to finalize the transition relief for first-time adopters. The transition relief proposed offers an optional exemption for a first-time adopter with RRA to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would not otherwise qualify for capitalization. On May 6, 2010, the IASB issued the omnibus *Improvements to IFRSs*, which included the expected amendment to IFRS 1 applicable to entities with RRA. We expect to elect this exemption for our regulated businesses.

The IASB directed its staff to continue its research and analysis and to focus on the key issue of whether regulatory assets and liabilities exist in accordance with the current IFRS framework and whether they are consistent with other standards. The IASB met twice on July 20 and July 22, 2010 to further discuss the proposals of the rate-regulated accounting project. The IASB did not arrive at any decision and decided to continue its analysis and outreach activities on the project. Subsequently, the AcSB met on July 23, 2010 and decided to propose an interim relief for rate-regulated entities by permitting them to defer their IFRS implementation date to January 1, 2013, which is pending approval by the CSA. The AcSB released an exposure draft on July 28, 2010. Hydro One intends to respond to the exposure draft. Given the recent proposed deferred transition date, we are assessing next steps. We will continue to assess the IASB's deliberation on the project. At this time, there is uncertainty as to how the OEB will respond. If rate-regulated accounting were not permitted, the discontinuance would result in a write-off of regulatory assets and regulatory liabilities for a net reduction to retained earnings of approximately $339 million as at December 31, 2009.

In-Progress Construction and Development

Under current IFRS, there is a significant difference to Canadian GAAP in terms of what costs can be capitalized to in-progress construction and development projects. The impact of this difference on our financial statements cannot reasonably be estimated until greater clarity is provided by the IASB on the future direction of its RRA project. We will continue to assess the outcome of the IASB's project and update the transition date impact on our financial statements.

Employee Future Benefits

Given that the RRA project has not been finalized at this point, it is unclear at this time whether the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis would be permissible. Regulatory assets and liabilities, representing the cumulative difference between our company's pension contributions accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, may not meet the definition of assets or liabilities under IFRS and hence may require de-recognition at the IFRS transition date. Similarly, we are assessing our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. Currently, the possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits*. Our policy choice may be contingent upon the outcome of the RRA project. The impact of using IFRS 1 as at December 31, 2009 would be a change to retained earnings of $852 million.

In April 2010, the IASB published an exposure draft, *Defined Benefit Plans (Proposed amendments to IAS 19 Employee Benefits)*, with significant implications for both financial position and income reporting. Deferred recognition of actuarial gains and losses would be eliminated and instead all changes in the defined benefit obligation and in the fair value of plan assets would be recognized in the statement of comprehensive income when those changes occur. The exposure draft also proposed a new presentation approach where the changes in the defined benefit obligation and the fair value of plan assets would be segregated and separately disclosed as service cost, finance cost and re-measurement adjustments. Service cost and finance cost components would be recognized in the statement of operations. The re-measurement adjustments representing actuarial gains and losses would be recognized as part of other comprehensive income. As per the IASB's revised timeline, the final standard is expected in the first quarter of 2011 with an effective date not earlier than 2013. The new accounting standard when adopted in 2013 or in later years will result in higher volatility in the statement of comprehensive income due to the recognition of the full amount of actuarial gains and losses.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with Canadian Institute of Chartered Accountants Handbook section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. If the RRA project is adopted as is, we plan to continue to record taxes on a cash basis instead of the liability method for the regulated businesses. Currently, we expect to record differences in items credited or charged directly to equity, financial instruments and unused tax losses and unused tax credits. If rate-regulated accounting is not permitted, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs as at December 31, 2009 would have been lower by approximately $46 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of our rate applications and the AcSB's proposed delayed IFRS implementation date.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first time adoption and additional internal controls may be required to implement changes in our accounting policies and to support our ongoing IFRS reporting requirements. Required changes to our control environment cannot be determined until such time as policy choices are finalized.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high-impact, based on the currently assessed risk of a major change being required upon implementation of IFRS. This ranking was completed in the fourth quarter of 2009. We completed updating the documentation for all of the low and medium-risk processes with IFRS implementation impact, including process documentation and risk and control matrices, during the second quarter. For our high-risk processes we are assessing timing for completion of our documentation revisions, subject to any decision made by the IASB on the RRA project. Process revisions on high-risk areas are being completed last due to the potential for impacts of the RRA project. Considering the proposed deferral in the IFRS implementation date and the uncertainties on the outcome of the project, we are assessing the completion date for the walkthroughs of the revised process and control documentation relating to low, medium and high-risk processes.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

The training of key finance and operational staff commenced in 2007 and has been on-going. Training has also been given to the Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion could have on our financial statements. These groups are updated as developments in IFRS continue. Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

Business Activities

The company has the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various exposure drafts under IFRS, we could undergo changes to our results that would impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer-sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we

have been analyzing the impacts of potential changes in accounting policy on our debt covenant and communicating potential scenarios and impacts analyses to our Audit and Finance Committee. Based on our calculations, we would remain in compliance with our debt covenants. However, we have met with our financial institutions and amended our credit agreement to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio will be modified for certain items to factor IFRS impacts, such that the debt to total capitalization ratio is representative of what it was prior to IFRS. We will continue to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS.

Information Technology (IT) Systems

As part of an entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system has been designed with the maximum flexibility given the uncertainty of rate-regulated accounting under the IASB's current project. Considering the proposed deferral in the IFRS implementation date and the uncertainties on the outcome of the project, we are assessing the degree of future required re-configurations in the new system.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

In 2008, we began transitioning our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

In 2008, we successfully implemented the first phase of the supply chain, asset and work management modules in SAP. In 2009, we successfully implemented various Finance, Human Resources, Payroll and Investment Management modules. The reporting tool Business Intelligence/Business Warehouse was also implemented. This implementation included new controls over Internal Controls over Financial Reporting and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended June 30, 2010, together with other financial information included in our quarterly securities filings. Our Certifying Officers have certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

2011-2012 Transmission Rate Application

On May 19, 2010, our subsidiary Hydro One Networks filed its rate application for 2011 and 2012 transmission rates. The application seeks the approval for a revenue requirement of approximately $1,446 million and $1,547 million for 2010 and 2011, respectively. This represents an estimated increase in rates of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill. These increases primarily reflect system expansion and asset replacement needs, including the Bruce to Milton Transmission Reinforcement Project, and other increases in our work program requirements. The requested rate increases will also support investments in respect of the OPA's supply mix policies, which include the phase-out of coal-fired generation and investments to address aging infrastructure.

Midtown Toronto Project

On June 17, 2010, the OEB issued a decision approving, subject to conditions, our Leave-to-Construct application for our Midtown Toronto Project to refurbish the existing 115 kV transmission infrastructure which serves midtown Toronto and areas to the west.

Conservation and Demand Management (CDM) Targets

On June 22, 2010, the OEB provided notice under the *Ontario Energy Board Act, 1998* of the creation of a proposed CDM Code for electricity distributors. The new code proposes CDM targets for all licensed electricity distributors as directed by the Minister of Energy and Infrastructure earlier this year. The proposed allocation of the overall targets to our Company for the reduction of peak provincial electricity demand, and for the reduction of electricity consumption are 256 MW and 1,208 GWh, respectively over the four-year period beginning January 1, 2011. This represents approximately 19.2% and 20.1% of the total target savings allocated to all distributors, respectively.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions) (except as otherwise noted)	**2010**	**2009**	**2010**	**2009**
Net income	105	82	274	259
Net cash from operating activities	257	192	544	373
Capital expenditures	383	383	705	719
Basic and fully diluted earnings per common share *(Canadian dollars)*	1.005	781	2.655	2.505
Earnings coverage ratio[1]			2.15	2.42
Net asset coverage on long-term debt[2]			1.76	1.79
Total debt to capitalization[3]			57%	56%

[1] The earnings coverage ratio has been presented for the twelve months ended June 30, 2010 and June 30, 2009, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2] The net asset coverage on long-term debt ratio has been presented as at June 30, 2010 and December 31, 2009 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] Total debt to capitalization ratio has been presented as at June 30, 2010 and December 31, 2009 and has been calculated as total debt divided by total debt plus total shareholder's equity.

APPOINTMENT OF JANET HOLDER

On July 1, 2010, Janet Holder was appointed to our Board of Directors. Ms. Holder is the President of Enbridge Gas Distribution and serves on the Board of Governors at the University of New Brunswick.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including amendments to codes, the impact of new regulatory guidelines and impacts of decisions from the OEB and other governing bodies; statements related to our rate applications and rate changes including estimated rate increases and expected impacts on an average customer's bill; statements regarding our future liquidity and capital resource requirements; expectations regarding our financing activities including our targeted long-term credit rating; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding future capital expenditures, budgets and our investment plans; statements related to smart meters, time-of-use pricing and the associated smart grid; statements regarding contractual obligations and other commercial commitments; statements regarding future pension contributions and our pension plan; and statements related to IFRS, the IASB, the AcSB, our conversion to IFRS, planned courses of action, and expected impacts in

the event of a discontinuance of regulatory accounting. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; the preparation of business plans, comparative numbers, regulatory filings and future capital expenditures on the basis that rate-regulated accounting will continue to exist under IFRS; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province;
- the impact of the final outcome of the exposure draft on rate-regulated accounting;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- investment returns, changes in benefits or actuarial assumptions;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned; and
- the impact of the GEA on our company and the costs and expenses arising there from.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2009 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at August 12, 2010. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Revenues				
Transmission	306	271	626	573
Distribution	842	803	1,825	1,789
Other	17	16	33	31
	1,165	1,090	2,484	2,393
Costs				
Purchased power	542	518	1,197	1,184
Operation, maintenance and administration	266	281	524	524
Depreciation and amortization	144	129	283	253
	952	928	2,004	1,961
Income before financing charges and provision for payments in lieu of corporate income taxes	213	162	480	432
Financing charges *(Note 6)*	88	74	173	146
Income before provision for payments in lieu of corporate income taxes	125	88	307	286
Provision for payments in lieu of corporate income taxes	20	6	33	27
Net income	105	82	274	259
Other comprehensive loss	-	-	-	-
Comprehensive income	105	82	274	259
Basic and fully diluted earnings per common share *(Canadian dollars)*	1.005	781	2.655	2.505

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Retained earnings, beginning of period	1,946	1,578	1,791	1,497
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	-	-	12
Net income	105	82	274	259
Dividends *(Note 3)*	(5)	(27)	(19)	(135)
Retained earnings, end of period	2,046	1,633	2,046	1,633

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Accumulated other comprehensive income, beginning of period	(10)	(10)	(10)	(10)
Other comprehensive loss	-	-	-	-
Accumulated other comprehensive income, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	June 30, 2010	December 31, 2009
Assets		
Current assets:		
Short-term investments	147	-
Accounts receivable (net of allowance for doubtful accounts)	808	843
Regulatory assets	67	72
Materials and supplies	21	21
Future income tax assets	26	21
Other	17	16
	1,086	973
Fixed assets:		
Fixed assets in service	18,818	18,407
Less: accumulated depreciation	7,034	6,815
	11,784	11,592
Construction in progress	1,526	1,256
Future use land, components and spares	143	150
	13,453	12,998
Other long-term assets:		
Regulatory assets	1,104	1,018
Deferred pension asset	392	424
Intangibles (net of accumulated amortization)	206	218
Goodwill	133	133
Future income tax assets	19	18
Other assets	10	13
Long-term investment *(Note 4)*	248	-
	2,112	1,824
Total assets	16,651	15,795

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	June 30, 2010	December 31, 2009
Liabilities		
Current liabilities:		
Bank indebtedness	39	26
Accounts payable and accrued charges	760	800
Regulatory liabilities *(Note 5)*	100	100
Accrued interest	79	74
Short-term notes payable	-	55
Long-term debt payable within one year *(Note 6)*	450	600
	1,428	1,655
Long-term debt *(Note 6)*	7,030	6,281
Other long-term liabilities:		
Employee future benefits other than pension	962	940
Regulatory liabilities *(Note 5)*	465	489
Future income tax liabilities	785	693
Environmental liabilities	294	303
Long-term accounts payable and other liabilities	14	16
	2,520	2,441
Total liabilities	10,978	10,377
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,046	1,791
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,673	5,418
Total liabilities and shareholder's equity	16,651	15,795

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Operating activities				
Net income	105	82	274	259
Environmental expenditures	(5)	(2)	(8)	(3)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	129	116	257	231
Retail settlement variance accounts	16	(1)	22	(3)
Special purpose charge *(Note 5)*	(10)	-	(10)	-
Regulatory liability refund account	(6)	(5)	(14)	(10)
Future income taxes	4	2	13	5
Smart meters	(4)	-	(11)	(1)
Rider 6 *(Note 5)*	(3)	(12)	(3)	(15)
Other regulatory asset and liability accounts	2	7	1	4
Amortization of debt costs	2	-	2	-
Rural and remote rate protection variance account	1	(7)	8	(9)
	231	180	531	458
Changes in non-cash balances related to operations	26	12	13	(85)
Net cash from operating activities	257	192	544	373
Financing activities				
Long-term debt issued	-	-	1,000	600
Long-term debt retired	(400)	-	(400)	(400)
Short-term notes payable	-	75	(55)	225
Dividends paid	(5)	(27)	(19)	(135)
Other	-	-	-	5
Net cash (used in) from financing activities	(405)	48	526	295
Investing activities				
Capital expenditures				
Fixed assets	(379)	(355)	(696)	(666)
Intangible assets	(4)	(28)	(9)	(53)
	(383)	(383)	(705)	(719)
Long-term investment	-	-	(250)	-
Other assets	12	3	19	15
Net cash used in investing activities	(371)	(380)	(936)	(704)
Net change in cash and cash equivalents	(519)	(140)	134	(36)
Cash and cash equivalents, beginning of period *(Note 8)*	627	120	(26)	16
Cash and cash equivalents, end of period	108	(20)	108	(20)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2009 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Income Taxes

Effective January 1, 2009, the Company adopted amendments to the CICA Handbook Section 3465 - *Income Taxes* and CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets. The temporary differences primarily relate to capital cost allowance in excess of deprecation and employee future benefits other than pension.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $20 million, long-term future income tax assets of $12 million and long-term future income tax liabilities of $503 million. The Company also recognized corresponding current regulatory liabilities of $29 million, long-term regulatory liabilities of $14 million and long-term regulatory assets of $526 million. An adjustment to retained earnings of $12 million was recorded as at January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

3. DIVIDENDS

During the three months ended June 30, 2010, preferred dividends in the amount of $5 million (2009 - $5 million) and common dividends in the amount of $nil (2009 - $22 million) were declared. During the six months ended June 30, 2010, preferred dividends in the amount of $9 million (2009 - $9 million) and common dividends in the amount of $10 million (2009 - $126 million) were declared.

4. LONG-TERM INVESTMENT

On January 22, 2010, Hydro One purchased $250 million in Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities. The Company has classified this investment as held-for-trading and therefore it has been recorded at fair value on the Consolidated Balance Sheet.

5. RATE-SETTING

Hydro One Networks Inc. (Hydro One Networks) Distribution Rate Decision

On April 9, 2010, the OEB released its decision regarding Hydro One Networks' rate application in respect of its Distribution Business. Subsequent to the decision, the OEB issued a final rate order which approved a revenue requirement of $1,146 million for 2010, reflecting a rate increase of approximately 9.3%. The proposed revenue requirement of $1,236 million for 2011 will be finalized following the Consensus Forecast in September 2010, when the 2011 return on equity is forecasted. As part of the decision, the OEB also approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of deferral accounts which track the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received under the approved rider. The OEB also approved a deferral account to record the revenue requirement impact of the harmonization of the provincial sales tax (PST) and federal goods and services tax effective July 1, 2010. Any estimated PST savings in approved rates will be brought forward for disposition in future rate applications.

As part of the decision, the OEB required Hydro One Networks to track the dollar value of variances between the OEB-approved line losses recovered in rates and actual line losses, commencing January 1, 2010. The OEB directed Hydro One Networks to bring this analysis forward to its next cost of service proceeding for the issue to be further examined.

The OEB further directed Hydro One Networks to investigate the effects of Conservation and Demand Management (CDM) programs on its load forecast, and required the Company to prepare analysis specific to its CDM actual volume reductions compared to forecast.

Currently, no amounts have been recorded for distribution lines losses and CDM. Management will continue to assess whether the results of the analysis in these areas requires the recognition of a regulatory liability.

Special Purpose Charge (SPC)

On April 9, 2010, the OEB issued a letter to all electricity distributors regarding the SPC Assessment under Section 26.1 of the *Ontario Energy Board Act, 1998*. The SPC has been established to enable the recovery of the expenses incurred and the expenditures made by the Ministry of Energy and Infrastructure (MEI) in respect of its energy conservation and renewable energy programs.

Along with the OEB's letter, the MEI set out the amount that Hydro One was assessed for the SPC, amounting to approximately $11.1 million. This amount was recorded in the OEB established variance account for the SPC, which captures any difference in the amount remitted for the SPC assessment and the cumulative amounts recovered from customers on account of the assessment. Recovery of the SPC assessment from customers commenced May 1, 2010, and is recovered on a volumetric basis.

6. LONG-TERM DEBT

During the six months ended June 30, 2010, Hydro One issued additional notes under the Company's Medium-Term Note Program.

The first issue on January 22, 2010 was an additional offering of 3.13% notes with a principal amount of $500 million. The notes mature on November 19, 2014 and were originally issued on November 19, 2009 for $250 million, bringing the total amount outstanding for this issue to $750 million.

The second issue on March 15, 2010 was an offering of 4.40% notes with a principal amount of $300 million. The notes mature on June 1, 2020.

The third issue on March 15, 2010 was an additional offering of 5.49% notes with a principal amount of $200 million. The notes mature on July 16, 2040 and were originally issued on July 16, 2009 for $300 million, bringing the total amount outstanding for this issue to $500 million.

On January 22, 2010, Hydro One entered into two $250 million notional principal amount fixed-to-floating interest rate swaps to convert $500 million of Hydro One's 3.13% coupon note maturing November 19, 2014, into three-month variable rate debt. The Company designated these swaps as fair value hedges associated with interest rate risk with the changes in fair value recognized in the Consolidated Statement of Operations for the period, along with changes in the fair value of the fixed rate note that is attributable to the hedged risk. To the extent the hedge is ineffective, the ineffective amount is recognized immediately to financing charges in the Consolidated Statement of Operations, and this amount was insignificant for the period.

In the second quarter, the Company entered into four forward rate agreements in order to lock-in four interest rate resets on the floating rate it pays on $500 million of floating rate debt, with settlement dates of May 19, 2010, June 3, 2010, August 19, 2010 and September 3, 2010 respectively. The four forward rate agreements were classified as held-for-trading and measured at fair value. The cash settlements on the first and second forward rate agreements were not significant and were made by the Company on May 19 and June 3, 2010 respectively. As at June 30, 2010, the fair value of the third and fourth forward rate agreements were losses of approximately $131 thousand and $139 thousand, respectively. These marked to market losses were recorded in the second quarter.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2010**	**2009**	**2010**	**2009**
Pension				
Net periodic benefit cost	46	33	91	65
Pension fund contribution	29	27	59	56
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	12	10	24	22
Charged to results of operations	17	17	35	34
Employee Future Benefits Other than Pension				
Net periodic benefit cost	23	20	45	40
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	8	18	16
Charged to results of operations	14	12	27	24

8. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "short-term investments" and "bank indebtedness."

9. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	306	842	17	1,165
Purchased power	-	542	-	542
Operation, maintenance and administration	103	148	15	266
Depreciation and amortization	66	75	3	144
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	137	77	(1)	213
Financing charges				88
Income before provision for payments in lieu of corporate income taxes				125
Capital expenditures	209	174	-	383
2009				
Segment profit				
Revenues	271	803	16	1,090
Purchased power	-	518	-	518
Operation, maintenance and administration	120	147	14	281
Depreciation and amortization	57	69	3	129
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	94	69	(1)	162
Financing charges				74
Income before provision for payments in lieu of corporate income taxes				88
Capital expenditures	218	163	2	383

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	626	1,825	33	2,484
Purchased power	-	1,197	-	1,197
Operation, maintenance and administration	210	285	29	524
Depreciation and amortization	130	148	5	283
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	286	195	(1)	480
Financing charges				173
Income before provision for payments in lieu of corporate income taxes				307
Capital expenditures	404	300	1	705

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	573	1,789	31	2,393
Purchased power	-	1,184	-	1,184
Operation, maintenance and administration	223	274	27	524
Depreciation and amortization	115	133	5	253
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	235	198	(1)	432
Financing charges				146
Income before provision for payments in lieu of corporate income taxes				286
Capital expenditures	405	311	3	719

(Canadian dollars in millions)	June 30, 2010	December 31, 2009
Total assets		
Transmission	9,438	9,118
Distribution	6,650	6,516
Other	563	161
	16,651	15,795

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

10. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2010 unaudited interim Consolidated Financial Statements.